SIMULATING THE PRODUCTION STRATEGIES FOR OPTIMIZATION OF THE GAS RECOVERY FROM A WATER DRIVE DRY GAS RESERVOIR

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ABSTRACT

The water drive is the most economical natural drive mechanism. The recovery factor of water drive dry gas reservoir is about 45-70% when produced under conventional restricted approach. The reason for this is that the water encroaches into the gas zone and traps the gas. Hence, the production strategies such as the conventional approach, blow down approach and coproduction on a heterogeneous reservoir to optimize the gas production may be used. The co-production strategy has provided the good results with an encouraging recovery factor. It may be found to be more economically feasible in comparison to other production strategies.

INTRODUCTION

In Pakistan, the current gas supplies are over 4,000 MMCFD whereas the current market demand is more than 6,000 MMCFD as reported by Pakistan Economic survey 2014-2015. The main reason for difference in gas supply and demand is the continuously reducing supply of natural gas from the existing fields and the slow rate of new gas discoveries, which has shown a decline in the past decades [1].

The drive mechanism plays a vital role in hydrocarbons recovery. There are three main types of gas reservoirs i.e. Dry, Wet & Retrograde Condensate Gas Reservoir. All these types have different properties and recovery factors. The depletion or volumetric and water drive are the major drive mechanisms in the gas type reservoir. Almost 80-90% of gas recovery may be obtained from depletion drive whereas recovery factor is 70-80% for partial water drive and 50-60% for active water drive mechanism as reported in literature [2-4]

RECOVERY TECHNIQUE

Nowadays, many reliable techniques have been practiced for enhancing the Ultimate Gas Recovery (UGR) from the sources like Water drive dry gas reservoir (WDDGR) [5]. Following are the most

considerable techniques which have used for optimizing the gas recovery from WDDGR:

1. **Conventional Production:** By this technique, (i) the restrained flow rates are departed throughout the wells and (ii) the production aborts when wells are watered-out.
2. **Blow-down:** By this technique, withdrawal gas production rates are enhanced in order to outrun the aquifer advances that may result in a boosted UGR.
3. **3. Co-production:** By this techniques, UGR can be increased by producing water from downdip/edge wells. This technique is helpful in depletion of aquifer and gas volume.

RESEARCH METHODOLOGY

The Eclipse 100 – Black Oil Simulator is used in this study. Following procedural steps have been implemented:

- Definition of the study objectives.
- Model description and selection
- Collection of relevant reservoir data.
- Validation of the data.
- Reservoir model construction.
- Formulation of the running model and prediction cases.
- Simulation and result analysis.

MODEL WORKFLOW

The workflow for model description is defined as below (Fig.1.):

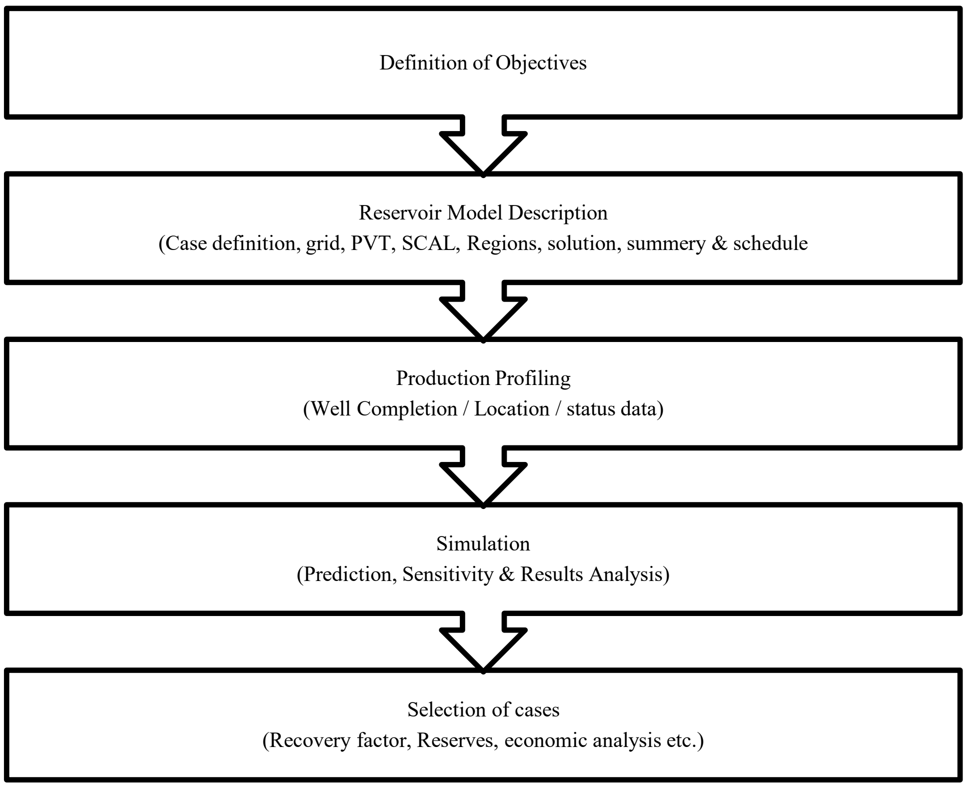

Figure 1: Model description workflow.

EFFECTS OF WATER DRIVE DRY GAS RESERVOIR ON ULTIMATE GAS RECOVERY

The stabilization pressure, mobility ratio, and aquifer size and production rates are all important parameters and have effects on the water drive dry gas reservoir.

The details of these effects are given below:

1. Effect of Stabilization Pressure

Through the volumetric recovery methods, the effect of pressure can easily be illustrated. For example, for any system, the gas saturation (Sg) is equivalent to the differentiation of initial gas saturation (Sgi) and the residual gas saturation (Sgr). But, to some extent, the amount of mobile gas saturation is captured by the overstep water in a WDDGR, called the trapped gas saturation.

It is further illustrated that Sgr is not dependent of pressure and may become a reason for greater recovery at the lower stabilization (abandonment) pressure. In case of higher stabilization pressure, the recovery will be smaller.

2. Mobility Ratio

Understanding the inimitable feature of the displacement of water in a gas reservoir is very vital. For that, practicable mobility (M) between the two fluids is to be considered. Basically, M is a ratio between the mobility of two fluids such as advancing fluid (i.e "Water" in case of WDDGR) and displaced fluid (i.e "Gas" in case of WDDGR).

For Darcy's law equation, mobility represents part of it and it is defined as a ratio between relative permeability to the viscosity of the given fluid. The movement of fluid depends upon the mobility of the fluids i.e a higher mobility will be a higher movement of fluid. For example, if M is 0.01:1 it would represent the water being an advancing fluid, travels 100 times slower than the gas or, in other words, the amount of gas being advanced is 100 times more rapid than water [6].

3. Aquifer size

The mass of aquifer is also of high importance and effects on UGR in any reservoir strategy and management approach. Bass Jr. and Al-Hashim conducted research on a homogeneous and radial type flow model and the findings of their research indicated that when $0 \le r_a / r_g < 2$, the aquifer effect on the gas reservoir's performance is negligible [7]. Aquifer effects the performance of a given reservoir when $r_a / r_g < 2$ as shown in table 1[8-9]. The Table 1 can be used to gauge the effect of production rate sensitization and aquifer size on performance.

Table 1: Effect of recovery sensitization and aquifer size on performance.

At r_a/r_g 1	**At r_a/r_g 4**
Effect: Negligible Sensitive rate: Not	Effect: Significant Sensitive rate: Significantly

At r_a/r_g 2 Effect: Minor Sensitive rate: Slightly	**At r_a/r_g 4** Effect: Significant Sensitive rate: Significantly
At r_a/r_g 3 Effect: Modest Sensitive rate: Moderately	**At r_a/r_g 6** Effect: High Sensitive rate: Highly

DATA GATHERING

For preparing the model for optimize gas recovery from WDDGR in Eclipse-100 black oil simulator, the following data had been taken from the "**X**" field'.

- Initial average pressure: 4927.87psia at a datum depth of 10745.76 feet.
- Reservoir volume: 932,933,085RB.
- Initial gas in place: 132 BCF.
- Initial water volume: 754.82 MMSTB.
- Gas water contact level at: 11161 feet.
- The reservoir is heterogeneous
- Region Averaged Grid Quantities
  PERMX = 185.38 md; PERMY = 185.38 md PERMZ = 34.34 md;
  PORO = 15.996% DZ = 63.875 ft
- Grid dimensions of the Reservoir-M

Direction	Locations of Grid	Grid average length in ft
X	14-25	658
Y	72-157	651
Z	109-114	10.97

- Grid description:

Model Dimensions	Grid Geometry	Grid Type
29 × 156 × 171	Cartesian	Corner Point

- Formation properties, Reservoir fluid properties, FVF and other relevant data are shown in table 2 to 5.

RESULT AND DISCUSSION

As discussed earlier field data and basic factors were used as input in a simulator which revealed the following results:

1. The simulation has been done from the period of 01-Jan-16 to 31 Dec, 2016 and achieved the successful results.
2. Field Gas Production is illustrated in Fig.2 and shows the gas production rate. Here the major point to note is that the gas production reached almost the same level, i.e 123000MSCF/D, on 1-Aug-2016 by blow down methods as well as the co-production technique. After that time, the gas production has decreased w.r.t time by blow down technique whereas it has increased when co-production technique is employed.
3. Fig.3 shows that the cumulative field gas production has 101363120MSCF/D by co-production technique as maximum (as compared with the blow down (i.e 88733176MSCF/D) and conventional (i.e 85823624MSCF/D) technique).
4. Fig.4 to Fig. 7 show the results with regards to field gas in-place, field gas pore volume and water production of conventional, blow down and co-production techniques.
5. Fig. 8 shows that the water advance is slow as co-production pressure is reduced in the water producing well. The overall pressure of the reservoir is reduced and the well static bottom hole pressure gets produced until the limiting tubing head pressure of 500 psi is achieved. Wells are shut due to pressure constraint and not due to High water gas ratios [10].

CONCLUSION

1. Co-production technique is observed to have played a vital role in producing the reserves at maximum rates, followed by blowdown and conventional technique.
2. Co-production technique demonstrated a greater impact in terms of techno-economic factors and relevant consideration as compared to other production strategies and techniques.
3. Intensity of the aquifer and well placement are both the prime point factors for an enhanced recovery. It is concluded that due to the excessive water cuts, the wells are shut in conventional and in blowdown technique whereas gas producers were shut due to the pressure reduction in co-production technique. Overall result is that the incremental reserves may be achieved better than blowdown technique.

ACKNOWLEDGEMENT

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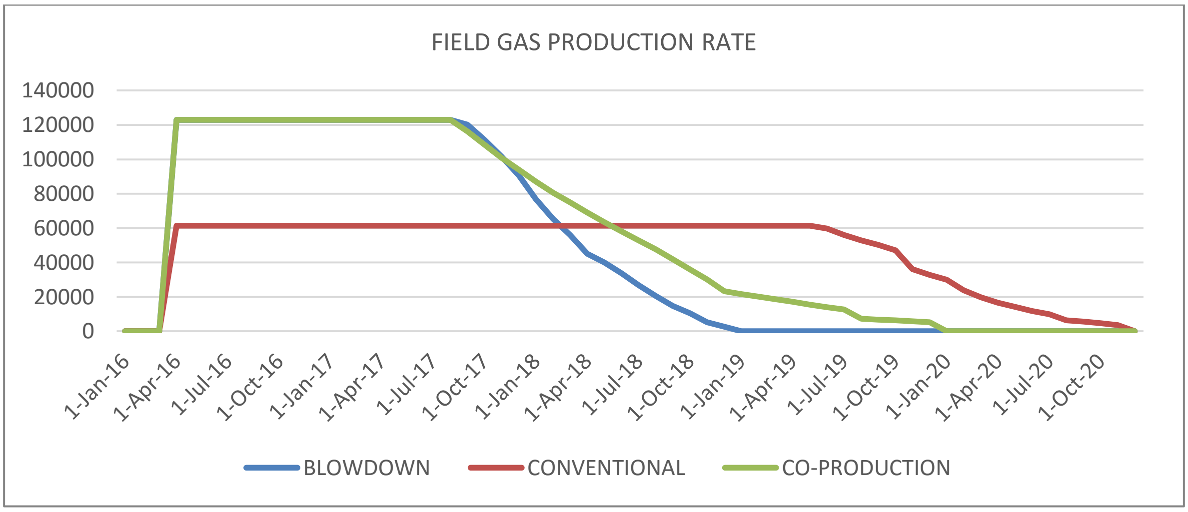

Figure 2: Field Gas Production Rate.

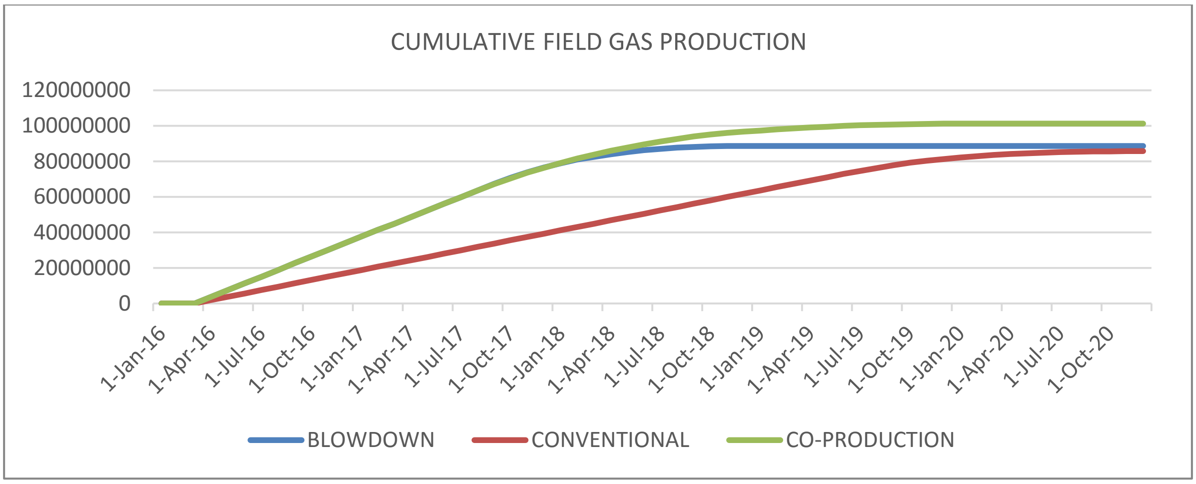

Figure 3: Cumulative Field Gas Production.

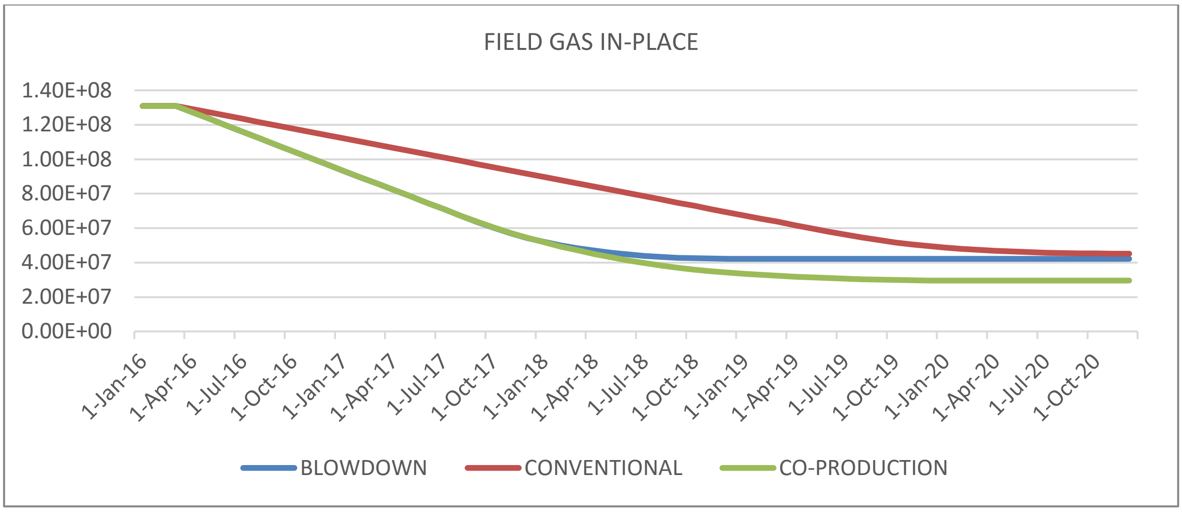

Figure 4. Field Gas In-Place.

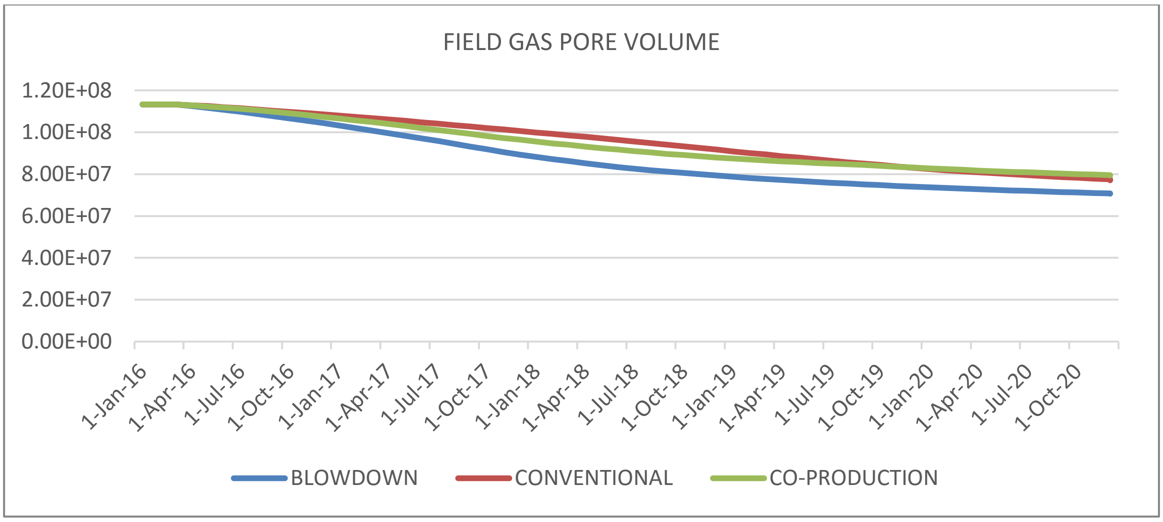

Figure 5: Field Gas Pore Volume.

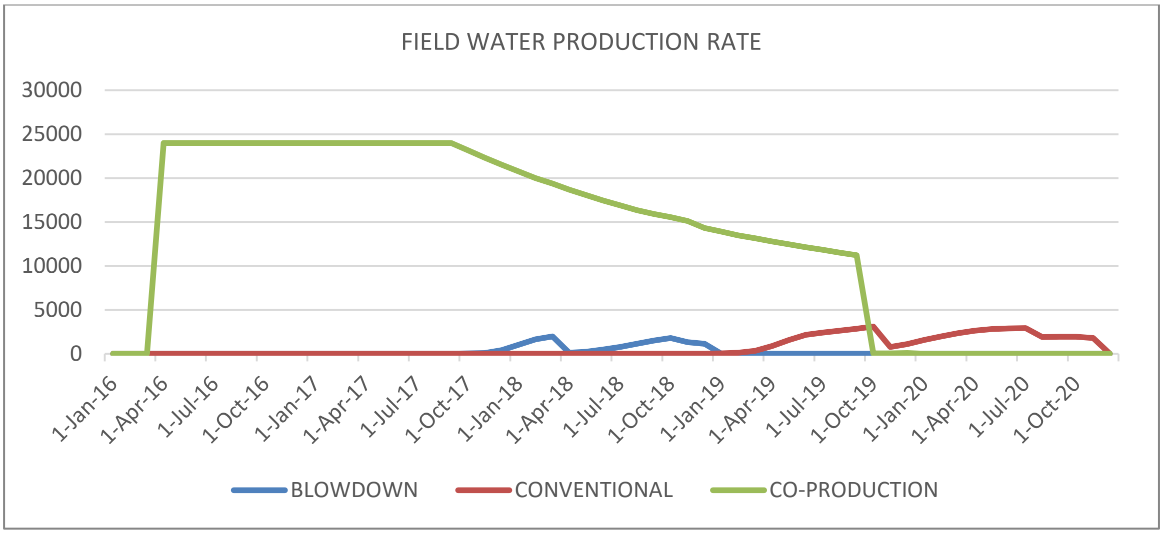

Figure 6: Field Water Production Rate.

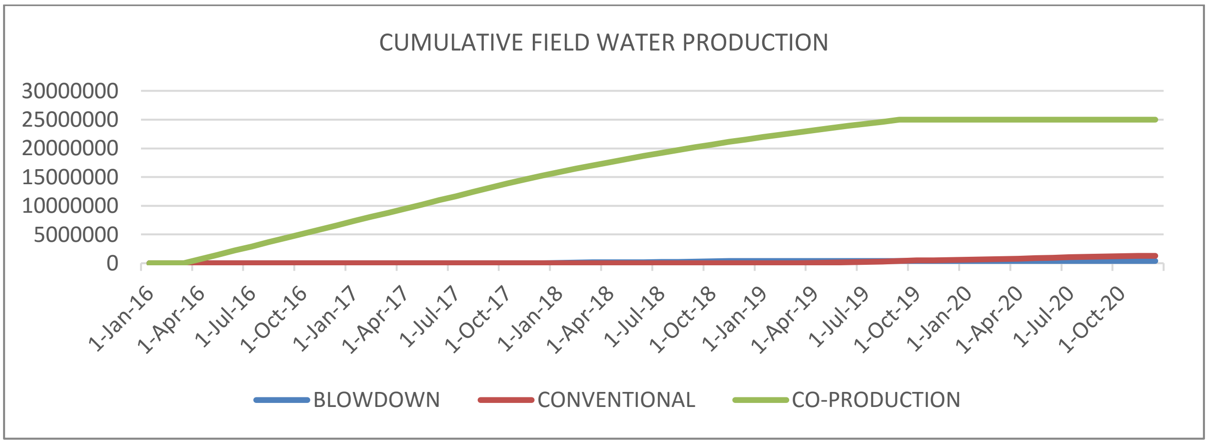

Figure 7: Cumulative Field Water Production.

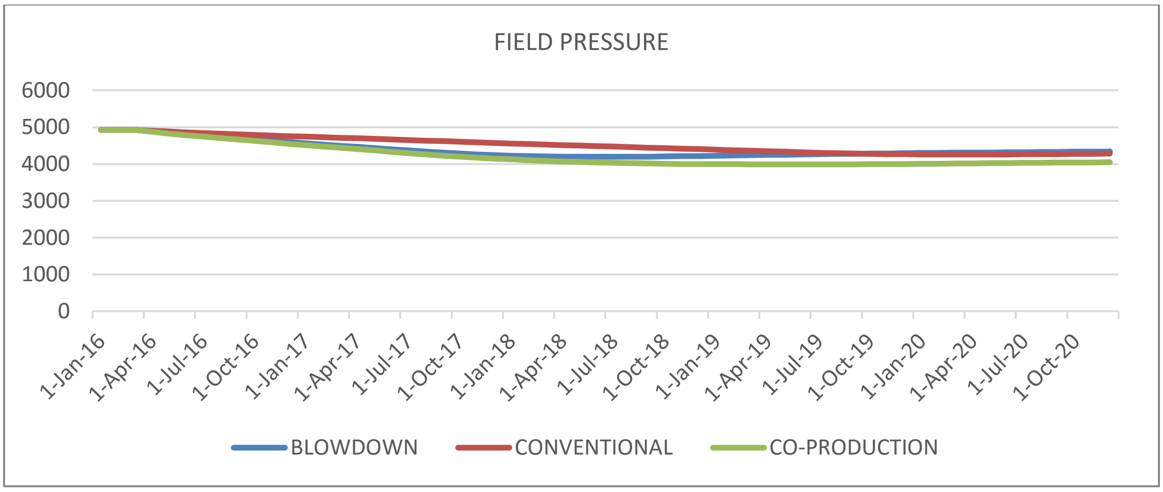

Figure 8: Field Pressure.

Table 2: Formation properties

Layer	Porosity	kx=ky (md)	kz (md)	Thickness
108	10% to 30%	0.1 to 1001	0.01 to 101	13.298 – 15.741
109		101 to 2001	10 to 201	10.433 – 12.576
110		11 to 1001	1 to 101	17.711 - 19.516
111		101 to 1001	10 to 101	14.069 - 15.356
Formation compressibility			1.808E-5 psi^{-1}	

Table 3: Reservoir Fluid Properties

Parameter	Set Value
Density of water	64.101 lb/ft^3
Density of gas	0.0507 lb/ft^3
FVF of water	1.088 RB/STB
Compressibility of water	4.3E-6 psi^{-1}
Viscosity	0.17 cp

Table 4: Gas FVF and gas as a function of Pressure.

Pressure value (psia)	Gas FVF(RB/Mscf)	Viscosity
16	270.511	0.014
501	7.891	0.0138
1001	3.937	0.0146
1501	2.619	0.0153
2001	1.960	0.0170
2501	1.586	0.0168
3001	1.337	0.0175
3501	1.159	0.0183
4001	1.034	0.0190
4501	0.927	0.0197
4869	0.873	0.0202
5001	0.855	0.0204
6001	0.730	0.0234

Table 5: FVF, compressibility and viscosity of water as a function of Pressure

Ref Pressure (psia)	Water FVF	Water Comp:	Water viscosity
4901	1.088	4.3E-6	0.17